

Service Date: October 20, 1981

DEPARTMENT OF PUBLIC SERVICE REGULATION
MONTANA PUBLIC SERVICE COMMISSION

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In the Matter of the Application by)	UTILITY DIVISION
The Montana-Dakota Utilities Company)	DOCKET NO. 81.1.2
to increase rates for electric service.)	PHASE II
)	ORDER NO. 4799c

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APPEARANCES

FOR THE APPLICANT:

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FOR THE INTERVENORS:

John C. Allen, Staff Attorney, Montana Consumer Counsel, 34 West Sixth Avenue, Helena, Montana 59624, appearing on behalf of and as MONTANA CONSUMER COUNSEL.

Phyllis A. Bock, Staff Attorney, Montana Legal Services Association, 301 Steamboat Block, Helena, Montana 59620, appearing on behalf of ACTION FOR EASTERN MONTANA.

FOR THE COMMISSION:

Brenda Nordlund, Staff Attorney, 1227 Eleventh Avenue, Helena, Montana 59620.

BEFORE:

THOMAS J. SCHNEIDER, Commissioner and Hearing Examiner
GORDON E. BOLLINGER, Chairman JOHN B. DRISCOLL, Commissioner
HOWARD L. ELLIS, Commissioner
CLYDE JARVIS, Commissioner

BACKGROUND

1. Montana-Dakota Utilities Company (MDU) is a public utility providing electric service to consumers in the eastern portion of Montana.

2. On January 5, 1981, MDU submitted an application for authority to establish increased rates for electric service, thus initiating Docket No. 81.1.2.

3. Docket No. 81.1.2 was bifurcated on February 17, 1981: Phase I would establish MDU's rate base and revenue requirements while Phase II would pertain to rate structure issues, specifically the allocation of revenue responsibility to and within the various customer classes.

4. Montana Consumer Counsel (MCC) and Action for Eastern Montana (AEM) were granted intervenor status in this docket.

5. A procedural order establishing dates for discovery, filing of testimony and hearing in regard to Phase II was issued on April 9, 1981.

6. On August 21, 1981, preliminary determination was made that Action for Eastern Montana was eligible for an award of costs of participation.

7. On September 1, 1981, pursuant to proper notice, a hearing was held on Phase II in Miles City, Montana. MDU, MCC, AEM and several public witnesses provided testimony at the hearing.

8. Coincidental to the issuance of this order, an order was issued in Phase I. Order No. 4799b establishes MDU's revenue requirement at approximately \$21,097,000.

9. This Order provides the rate structure at which MDU shall establish rates which generate the authorized Phase I revenues.

10. This Order provides the Commission's findings in respect to only class revenue, rate structure, tariffs, and time-of-day rates. At some later date, the Commission will issue an additional order in respect to interruptible rate provisions, load management and load research, and all other remaining issues resulting from the Phase II proceeding.

FINDINGS OF FACT

COST OF SERVICE

11. MDU presented two cost of service studies as evidence: an embedded, fully allocated cost of service study (FACOSS) prepared and sponsored by Mr. C. E. Chick of Stone and Webster Management Consultants, Inc. (Stone and Webster), and a marginal cost of service study performed and presented by Mr. Malcolm R. Ketchum of Stone and Webster. Mr. C. Wayne Fox, MDU's Assistant Treasurer-Regulatory Affairs, testified that both embedded and marginal cost studies should be used to design rates. He stated that embedded cost-based rates belie the spiralling costs affecting all modes of MDU's operation and that such rates lead to a misallocation of resources. Mr. Fox contended that rates reflecting marginal cost principles would more accurately reflect the cost of providing service to customers, however, because of the uncertain nature of marginal cost estimates and costing methodologies, he advocated that the Commission move slowly in implementing marginal cost-based rates. To that effect, he testified that total and class revenue requirements should be based on fully allocated embedded costs.

12. The fully allocated cost of service study prepared by Mr. Chick assigned production and transmission demand related costs and investment on the basis of unweighted peak and average demand responsibility. Energy costs were allocated on the basis of energy consumption by class without reference to time of use.

13. The marginal cost study presented by Mr. Ketchum allocated the marginal capacity costs of generation, transmission and distribution by class coincident peak, the marginal energy costs by monthly on and off peak period kilowatt hour (kwh) sales, and the marginal customer costs by the average annual number of customers. The sum of the allocated marginal demand, customer, and energy costs yields the marginal-based class revenue requirement.

14. Dr. Robert Logan, and economist with J. W. Wilson and Associates, Inc. and one of MCC's witnesses, presented a marginal cost study which allocated marginal bulk power capacity costs by class coincident peak, marginal distribution costs by class non-coincident peak, marginal energy costs by on and off peak class energy consumption, and marginal customer costs in accordance with vectors established in Docket No. 6695, Order No. 4635c, Finding No. 18. Dr. Logan used Dr. George Hess' embedded cost figures from Phase I for distribution and customer costs as an approximation of long-run marginal costs, therefore, only the bulk power supply cost components of total marginal-based revenue requirements diverged from embedded cost-based requirements.

15. Dr. Thomas Power, AEM's witness, also testified to the merits of rates based on marginal costs. Dr. Power did not present a marginal cost study but instead offered testimony analyzing and critiquing the studies in evidence. He suggested that neither study should be relied upon to design rates unless sufficient information could be garnered from the record to correct the errors contained in each. He advised the Commission to "move...rates in the direction both studies indicate is appropriate, [placing] a heavier emphasis on energy cost responsibility." (Exh. AEM2, p. 19.)

16. All parties to the proceeding endorse long-run marginal or incremental costs (LRIC) as the proper basis for structuring MDU's electricity rates. The Commission, as well, finds that the proper basis for structuring rates is indeed LRIC. To the maximum extent practicable, rates should reflect unit LRIC, structured so that each class generates revenue reflecting class LRIC.

17. The Commission finds, in light of the testimony of Messrs. Fox, Ketchum, Power and Logan, that electricity priced to reflect LRIC will result in an optimal amount of production and consumption at the lowest possible cost.

18. In pursuit of LRIC, the Commission has reviewed the alternative cost of service studies presented. In its review the Commission has found portions of both studies in error.

19. Evidence in the record indicates that both studies result in inflated customer and demand LRIC calculations - inflated with costs which are found to be truly energy-related. Inflated customer costs in both studies result from the usage of the minimum distribution concept. Inflated demand costs result from Mr. Ketchum's classification of marginal transmission and distribution as totally demand-related and Dr. Logan's total disregard of numerous energy-related costs.

20. The Commission finds that the proper approach in arriving at class and unit LRIC is to utilize Mr. Ketchum's analysis and to offset the resulting demand/energy/customer imbalance in the conversion of LRIC to rates.

21. Mr. Ketchum's analysis is chosen for several reasons. Primarily, in that his treatment of costs is exhaustive, be they miscategorized. Dr. Logan's analysis, on the other hand, totally disregards the bulk of transmission costs, working capital requirements, administrative and general expenses (A&G), etc., which virtually precludes its usefulness in establishing LRIC. Dr. Logan's study can be used, where applicable, as a check for reasonableness. Following is a detailed review of Mr. Ketchum's analysis, leading to calculations of class and unit LRIC.

Rating Periods

22. Mr. Ketchum examined the hourly marginal energy costs and loss of load probability to establish rating (costing) periods as shown below.

Seasonal:

Winter: November through February

Summer: All other

Daily:

Peak: Monday through Saturday

Off-peak: Sunday and Holidays

Hourly:

Peak: 7:00 a.m. to 10:00 p.m. Monday through Saturday during the winter and

8:00 a.m. to 10:00 p.m. during the summer season

Off-peak: All other

23. Dr. Logan arrived at rating periods similarly. He proposed and calculated no seasonal cost differentials and by averaging weekends, found no distinction between Saturdays and Sundays.

24. Seasonal rating is not proposed by any party to proceeding, so the seasonal distinction is valuable information but, not considered in structuring rates. However, an examination of the Saturday hourly marginal energy costs and loss of load probability does suggest that Saturdays do belong in the peak rating period. The Commission, therefore, finds Mr. Ketchum's rating periods acceptable, but notes that the distinction between Saturday and Sunday costing is weak.

25. The Commission also finds that, for rate simplicity reasons, the peak hours cannot vary by season. The peak period will be adequately covered by a time period of 8:00 a.m. to 10:00 p.m., Monday through Saturday, regardless of season.

Marginal Energy Costs

26. Ketchum's marginal cost study utilized Stone and Webster's proprietary MARGIN program to model marginal energy costs. The data base was the Section 133 marginal energy costs (July, 1979 through June, 1980) projected for 1981 through 1985 and estimated for on and off-peak periods for each of three seasons. The three seasons reflect MDU's bimodal seasonal peaks. Schedule 1

provides the MARGIN results. Schedule 2 provides the same results after collapsing the seasonal differentials, adding in A&G, and working capital requirements, and adjusting for line losses.

27. Each customer class is allocated its marginal energy cost responsibility by multiplying the marginal energy cost shown in Schedule 2 by the estimated class test year peak and off-peak kwh consumption for TOD rates, and total test year consumption for non-TOD rates.

Schedule 1

MARGIN Marginal Energy Costs (¢/kwh)

	Peak	Off-Peak
Winter	3.438	2.292
Summer	2.677	1.796
Off-season	2.187	1.662

Schedule 2

MDU Marginal Energy Costs (¢/kwh)

	Peak	Off-Peak	Non-TOD
Residential/Schedule. 10	3.196	2.208	2.807
(secondary)	3.173	2.195	2.879
Commercial/Schedule. 20 (sec. & prim.)	3.135	2.176	2.680
Industrial/Schedule. 30 (sec. & prim.)			

28. Dr. Logan's study results in, for as of yet unexplained reasons, marginal energy costs of only half the magnitude of Mr. Ketchum's. The fact that the divergence remains unexplained is not surprising. Both studies result in "black box" calculations of marginal energy costs that this Commission has had to regularly accept. The hourly marginal energy costs are based on a myriad of system factors including variable O&M and fuel costs of the marginal generating unit, purchased power expenses, maintenance and outage requirements and system hourly load. It is never explicitly stated what the time differentiated marginal energy costs reflect. Whether the peak, off-peak, winter or summer

marginal energy cost reflect the running costs of a combustion turbine (CT), base load plant, or pool purchase remains obscured by the black box.

29. For example, it remains unclear why Mr. Ketchum's winter and summer marginal energy costs reflect a 30 percent differential despite the fact that the peak loads are nearly equal and projected to remain nearly equal.

30. For purposes of structuring rates, the Commission accepts those costs established by Mr. Ketchum and as shown in Schedule 2. However, the Commission wishes it to be known that it fully intends to avoid black box situations in the future.

Marginal Demand Costs

31. Stone and Webster's perturbation capacity costing methodology hypothesizes a peak load decrement of magnitude capable of deferring 100 MW of base load generating capacity by one year. In the case of MDU, this amounts to a 14.2 MW decrement deferring 100 MW from 1987 to 1988. The difference in the stream of capacity costs with and without the deferral is the load decrement (14.2 MW) multiplied by the installed cost of the 1987 base load plant (\$920/kw in 1980 dollars), or \$13.1 million.

32. From the capacity cost savings of 13.1 million, the increased operating costs (or foregone fuel savings) are subtracted from the capacity cost savings, resulting in net cost savings of \$183.31/kw (\$13.1 million-\$10.5 million/14.2MW). This figure is then annualized and adjusted for overhead and related expenses, and working capital, resulting in a marginal capacity cost of \$44.92/kw.

33. Transmission and distribution plant and expenses were separated into demand-related and customer-related based on the "minimum distribution system" concept and the Company's FACOSS. A linear regression linked the demand-related costs to incremental load, resulting in marginal demand related transmission and distribution costs of \$327.75/kw and \$152.04/kw, respectively.

When annualized and adjusted to reflect general plant, O&M, etc., the resulting marginal transmission and distribution costs are \$66.04/kw and \$31.80/kw, respectively.

34. The sum of the marginal capacity, transmission and distribution, after loss adjustments, yield the marginal demand costs for both secondary and primary voltage of \$158.25/kw and \$153.67/kw, respectively. The marginal demand costs multiplied by the Schedule. 10. 20 and 30 coincident kw at the meters yields class marginal demand cost responsibility. For nondemand metered customers, the demand costs are recovered in energy charges. For time-of-day rates, the marginal demand costs are allocated to only the peak costing period to be recovered in on-peak energy charges. For demand metered customers, the costs are recovered by nontime differentiated rates derived by dividing the class costs by the test year kw billing determinants.

35. Schedule 3 provides a summary of the marginal demand costs proposed by MDU.

Schedule 3

MDU Marginal Demand Costs (\$/kw)

	Secondary Voltage	Primary Voltage
Marginal Capacity Costs	\$ 50.14	\$ 48.69
Marginal Transmission Costs	73.71 <u>34.40</u>	71.58 <u>33.40</u>
Marginal Distribution Costs		
Marginal Demand Costs	\$158.25	\$153.67

36. Whereas the cost studies utilize similar methodology in their calculations of energy and customer costs, they diverge in regards to calculations of marginal demand costs. Dr. Logan correctly uses the installed cost of a combustion turbine to derive an estimate of marginal capacity costs. MDU argues that this approach is in error due to the Company's exclusively base load generating expansion plans. However, the fact that the system's load factor dictates base load expansion is totally irrelevant. A combustion turbine clearly represents the least cost source of capacity and therefore accurately represents the portion of base load generation costs attributable to demand. Dr. Logan's calculation of the marginal capacity costs associated with a CT generally endorse Mr. Ketchum's calculation. However, the studies diverge at that point. Dr. Logan allocates only the bulk transmission associated with demand-related capacity and goes to the FACOSS for demand-related distribution costs.

37. The appropriateness or inappropriateness of Mr. Ketchum's calculation of marginal demand costs is not well established. Clearly a large portion of the installed cost of a base load plant is incurred to provide energy; peak and off-peak energy. One could then look at Mr. Ketchum's estimate of

deferred base load savings and presume an over allocation of energy-related costs to the demand category. However, if the fuel savings estimated by Mr. Ketchum, and appropriately deducted from the installed capacity cost savings, are reflecting the displacement of combustion turbine running costs, then his calculation of marginal capacity costs are correct. A comparison with Dr. Logan's calculation appears to suggest that this is indeed the case.

38. Although the Commission finds Mr. Ketchum's calculation of marginal capacity costs acceptable, it finds fault in his calculation of the remaining marginal demand costs. Mr. Ketchum categorizes all noncustomer-related transmission and distribution investments and expenses as demand related, rather than, with the exception of CT remote siting transmission, energy-related as this Commission finds is the proper approach.

39. Dr. Logan, on the other hand, calculates a demand-related marginal transmission cost of magnitude nearly 20 times less than Ketchum. Dr. Logan's nondemand-related transmission is never accounted for in his study and his embedded distribution costs are never explicitly allocated to demand or energy. The result is Mr. Ketchum's estimate of demand costs is roughly twice that of Dr. Logan.

40. The Commission finds that the marginal demand costs proposed by MDU and reluctantly accepted by the Commission are inflated with an energy-related component. Three direct results of the energy/demand misallocation are significant. First, since class demand-related cost responsibility is allocated in relatively greater proportions to Sch. 10, the residential class will bear a greater proportion of costs than would otherwise be the case. Secondly, since demand-related cost is, in its entirety, dumped onto the peak period, an excessive peak/off-peak price differential results. Thirdly, in the case of demand-metered customers, the demand charges will be inflated at the cost of appropriate energy charges.

41. It should be noted at this time that Dr. Logan's study, indirectly, and to a slightly lesser extent, results in the same misallocation. By failing to consider numerous energy-related costs, and subsequently increasing his demand-riddled marginal bulk power supply costs by 38 percent to compensate, the true energy/demand cost ratio is skewed to the demand side.

Marginal Customer Costs

42. Mr. Ketchum's marginal customer costs were derived by summing the annualized minimum distribution system, distribution expenses, customer accounts and informational expenses, A&G, and working capital requirements. Schedule 4 provides the resulting annual and monthly customer costs.

Schedule 4

Annual Marginal Customer Costs

	Sch. 10	Sch. 20 & 30
Annualized Minimum customer	\$ 44.56	\$ 58.12
Investment	23.92	23.92
Distribution Expenses	25.91	28.20
Accounts & Information	6.87	7.19
A&G	<u>6.26</u>	<u>6.13</u>
Working Capital		
Annual Customer Costs	\$107.52	\$123.56
Monthly Customer Costs	\$ 8.96	\$ 10.30

43. Dr. Logan's estimate of customer costs was arrived at by applying customer class allocation factors to Mr. George Hess' MCC sponsored Phase I customer-related embedded costs. The allocation factors represent the proportional allocation of customer costs to each customer class in Docket No. 6695. His resulting proposal reflects Sch. 10 customer costs similar to those provided in Schedule 4, while his Sch. 20 and 30 charges are significantly higher.

44. Dr. Power ardently argues the inappropriateness of utilizing the minimum distribution concept in calculating customer costs. In his rebuttal testimony, Dr. Power demonstrates that his concept of base customer costs -- meters, billing, and service drop -- are more statistically related to marginal customers than are those costs proposed by Mr. Ketchum.

45. Drs. Logan and Wilson also concede that the marginal customer costs presented to this Commission are diluted with energy costs.

46. The Commission finds that the calculations proposed by both MDU and MCC in error in that they result in a misallocation of distribution-related investments and expenses to the customer cost category. Since 81 percent of Mr. Ketchum's customer costs are allocated to the residential class (as opposed to 22

percent of energy and 40 percent of demand), the Sch. 10 customers will continue to bear some as of yet unknown amount of Sch. 20 and 30 energy and demand costs in the form of customer cost responsibility.

Total Marginal Costs/Unit LRIC

47. Mr. Ketchum's marginal cost study results in functional marginal costs, per customer class, as indicated below.

Schedule 5

Unit LRIC

	Sch. 10	Sch. 20 Secondary Primary		Sch. 30 Secondary Primary	
Marginal Energy Costs (¢/kwh)	2.807	2.879	2.879	2.680	2.680
Marginal Demand Costs (\$/kw)	158.25	158.25	153.67	158.25	153.67
Marginal Customer Costs (\$/bill)	8.96	10.30	10.30	10.30	10.30

48. Accepting MDU's proposed LRIC, as they appear in Schedule 5, leads to LRIC class revenue responsibility as summarized in Schedule 6.

Schedule 6

LRIC Revenue Responsibility by Function
and Customer Class
(000 \$)

	Energy	%	Demand	%	Customer	%	T	%
Sch.	2,855	29.2	3,679	39.5	1,913	80.8	8,447	39.4

10	3,129	32.0	2,818	30.3	453	19.1	6,399	29.8
Sch.	<u>3,788</u>	38.8	<u>2,809</u>	30.2	<u>2</u>	-0-	-	30.1
20	9,772	100.	9,305	100.0	2368	100.0	<u>6,599</u>	100.0
Sch.		0						
30							21,445	

	Sch. 10	Sch. 20	Sch. 30
Energy	33.8%	48.9%	57.4%
Demand	43.6	44.0	42.6
Customer	<u>22.6</u>	<u>7.1</u>	<u>-0-</u>
Total	100.0%	100.0%	100.0%

Revenue Reconciliation

49. Given their LRIC calculations, Dr. Logan and Mr. Ketchum propose revenue reconciliation based on equi-proportional adjustment and embedded costs, respectively.

50. Mr. Ketchum calculates the ratio of class LRIC to class embedded accounting costs and scales down the class LRIC by that ratio. This method of revenue reconciliation is rationalized by Mr. Fox and Mr. Ketchum in terms of the state-of-the-art in developing class-LRIC.

51. Dr. Logan adjusts upward his calculations of class LRIC by the ratio of total LRIC to the total revenue requirement.

52. Dr. Power proposes an equi-proportional revenue reconciliation, as well, but only after a shift of \$400, 000 of revenue responsibility from the residential class in the form of his lifeline proposal.

53. The Commission chooses in this proceeding to reconcile LRIC revenues with authorized Phase I revenues by applying an equi-proportional adjustment. Dr. Power's proposal to shift revenue, albeit a minor shift which could be justified in light of the energy/demand/customer cost classifications presented to the Commission, is found inappropriate. The Commission finds the best

approach is one where class LRIC responsibility is maintained, irrespective of rate design.

54. The Commission also rejects the use of the Company's embedded FACOSS. The Commission has grave difficulties rationalizing the Company's purported relationship of accounting costs with cost causation. Utilizing the FACOSS would represent a major step backwards from ratemaking based on economic cost causation. The Commission's experience clearly suggests that the deficiencies associated with calculations of LRIC are equally prevalent in embedded cost of service studies. Furthermore, the fact that the FACOSS does not provide time differentiated costs is totally unacceptable.

55. Phase I established an authorized revenue requirement of approximately \$21,097,000. This amount represents 88.1 percent of the Company's proposed revenues. Applying the 88.1 percent to the sum of the Company's proposed Sch. 10, 20 and 30 revenues results in a Sch. 10, 20 and 30 authorized revenue level of \$16,783,000 -- or 21.7 percent less than the LRIC of \$21,445,000.

56. The Commission finds that the proper approach to establishing class revenue responsibility lies in an equi-proportional, 21.7 percent, adjustment to the class LRIC revenues shown in Schedule 6. Provided in Schedule 7 is the resulting class revenue responsibility, along with those implicitly proposed by MDU and the MCC.

Schedule 7

Class Revenue Responsibility (000 \$)

	Equi. Adj. of MDU LRIC (accepted)		Emb. Adj. of MDU LRIC		Equi. Adj. of MCC LRIC (existing)	
Sch. 10	\$ 6,614	39.4%	\$ 6,481	38.6%	\$ 6,885	41.0%

Sch. 20	5,010	29.8	5,810	34.6	5,698	33.9
Sch. 30	<u>5,166</u>	<u>30.1</u>	<u>4,500</u>	<u>26.8</u>	<u>4,208</u>	<u>25.1</u>
Total	\$16,791	100.0%	\$16,791	100.0%	\$16,791	100.0%

57. As shown in Schedule 7, the accepted Sch. 10 class revenue responsibility is straddled by those proposed by MDU and the MCC. However, Mr. Ketchum's LRIC calculations suggest a substantial shift of revenue responsibility from Sch. 20 to Sch. 30, relative to both the embedded allocation and Dr. Logan's partial LRIC calculations. While the divergence from the embedded allocation is simply a result of the embedded/LRIC relationship, the divergence from the MCC LRIC is less obvious. The divergence is partially explained by Mr. Ketchum's relatively larger proportion of demand (30% vs. 28%) and energy (39% vs. 37%) allocated to Sch. 30 and smaller proportion of customer cost allocated to Sch. 20 (19% vs. 39%). The remaining divergence remains obscured by their respective treatment of transmission and distribution.

RATE STRUCTURE

Residential/Sch. 10

58. MDU proposed a residential rate structure characterized by a \$5 minimum bill and an energy charge with two declining blocks. The minimum bill concept was proposed by Mr. Fox for purposes of customer understanding. The declining energy charges proposed by Mr. Chick were structured to reflect the recovery of customer costs in an initial block of 300 kwh.

59. The MCC rate structure witness, Dr. J. W. Wilson, initially proposed a \$4 customer charge with a flat energy charge, but later conceded that he thought it fully appropriate to recoup customer charges by means of a flat energy rate.

60. Dr. Power proposed a minimum bill of \$2 .90 and a "lifeline-like" energy charge. His proposed lifeline-like energy charge is composed of two blocks: a 300 kwh lifeline block reflective of "essential needs" and a second block implicitly reflecting nonessential needs. The two blocks would be priced at a differential such that the second block is reflective of LRIC and the first block priced lower to reflect class revenue requirement and a lower cost for essential needs.

61. The Commission has before it, for consideration, the full range of alternative residential rate structures: declining block, flat, inverted and a lifeline; with and without a customer charge.

62. Mr. Chick attempts to demonstrate a declining cost causation in residential consumption with an examination of diversified load factor. Dr. Power, using an alternative grouping of customers and annual rather than monthly diversified load factors, argues the opposite. The Commission, not overly impressed with either argument, finds the Company's proposal unacceptable. Mr. Chick, under cross-examination (Tr. p. 163), admits that because of the Company's deficient load research efforts, MDU is merely proposing a continuance of the historical rate structure which originated in the days of declining costs. The Company's proposal to give consumer's a declining energy cost signal is totally inconsistent with the reality of today's electricity production and consumption.

63. Dr. Power describes his "lifeline-like" proposal as a multi-objective proposal with two clearly distinctive objectives: economic efficiency and social equity. The Commission wishes to address each objective separately. First, is the Commission's findings in respect to inverted, or conservation, rates based on the principals of economic efficiency. As opposed to lifeline rates, inverted rates can apply to all customer classes and, in times of declining costs, could be (and were) not inverted rates, but declining block rates.

Inverted Rates/Economic Efficiency

64. Dr. Power's economic efficiency argument is, succinctly, that when consumers realize a cost associated with electricity consumption that reflects less than the economic costs that society incurs to provide the electricity, then each unit of electricity produced and consumed, at the margin, results in a net loss in social well-being. Conversely, it is only when the consumer is charged a rate reflective of economic costs, that the consumption of electricity, at the margin, results in benefits equivalent to the costs of providing the electricity.

65. The level of those economic costs, properly reflected by the class LRIC, is not well established in this proceeding. If one were to find that the marginal customer cost provided in Schedule 5 were an accurate portrayal of nonenergy-related costs, then the resulting Sch. 10 unit LRIC would be 6.424/kwh, as shown below.

$$\begin{array}{rcl}
 \text{Energy} & 6.424 * 101,720,277 \text{ kwh} & = \$6,533,520 \\
 \text{Customer } \$8.96 & * 213,516 \text{ bills} & = \underline{1,913,103} \\
 & & \$8,446.623
 \end{array}$$

66. As previously mentioned, Dr. Power, however, argues that the customer cost calculations proposed by both Mr. Ketchum and Dr. Logan, are in error:

Those customer costs include a substantial portion of the costs of the distribution system. As Dr. Logan says "The principle determinants of distribution costs are system costs which reflect maximum demands and energy volumes, plus energy losses. " (p. 47 at 11). Thus those costs should be allocated on the basis of energy and demand, not allocated, as proposed, on a per customer basis.

Some of the calculated "customer costs" cover sales expenses, customer information, advertising, and energy conservation programs. The value of these to the utility and to the customers is likely to be proportional to the customers energy and demand usage. Energy conservation expenditures are the equivalent of long run energy and demand purchases and should be allocated

accordingly, not charged to the residential class on a per customer basis.

The only costs which should be treated as customer costs are the costs of metering and billing. These "basic" customer costs are a maximum of between \$2.50 and \$3.00 per month per residential customer. (Exh. AEM2, p . 5)

67. Drs. Logan and Wilson concede (Tr. pp. 247, 251, 253) as well, that the customer cost calculations presented to the Commission are truly diluted with energy-related costs.

68. If one were to find that the customer costs proposed by Dr. Power, \$2.90, were correct and that the remainder were related to incremental energy load, then the resulting unit LRIC would be 7.704/kwh.

$$\begin{array}{rcl}
 \text{Energy} & 7.704 * 101,720,277 \text{ kwh} & = \$7,827,427 \\
 \text{Customer } \$2.90 & * 213,516 \text{ bills} & = \underline{619,196} \\
 & & \$8,446,623
 \end{array}$$

69. The Commission finds that the customer cost calculations are indeed diluted with some unknown level of energy costs sensitive to strictly marginal load, and not the marginal customer hooking on to the system.

70. As opposed to unit LRIC, the Commission must-design rates which generate the Company's revenue requirement based on accounting costs as provided in Schedule 7. Dr. Wilson's flat energy rate, with customer charges of \$4.00, or a minimum bill of \$5.00 as proposed by Mr. Fox, would result in energy charges of \$5.6634/kwh and, approximately, 6.4404/kwh, respectively.

$$\begin{array}{rcl}
 \text{Energy} & 5.6634 * 101,720,277 \text{ kwh} & = \$5,760,186 \\
 \text{Customer } \$4.00 & * 213,516 \text{ bills} & = \underline{854,064} \\
 & & \$6,614,250
 \end{array}$$

$$\begin{array}{rcl}
 \text{Energy} & 6.4404 * 101,004,079 & = \$6,504,250 \\
 \text{Customer } \$5.00 & * 22,000 & = \underline{110,000} \\
 & & \$6,614,250
 \end{array}$$

71. The Commission finds that the flat rates found with a customer charge of \$4 are far from reflective of the economic costs incurred as a result of electricity consumption. Furthermore, the Commission finds that the proper classification of costs would result in unit LRIC more reflective of 7.704/kwh than 6.424/kwh. The Company is therefore directed to design a Sch. 10 tariff applicable to all residential customers, which provides a minimum bill of \$2.90 and two inverted blocks. A first block of 300 kwh is to be priced at the rate found prior to the Phase I proceeding, 4.3534/kwh, and the second block, for levels of consumption greater than 300 kwh, at a rate such that the residential class test year sales generates the residential class revenue responsibility. Such Sch. 10 rates will resemble those provided below.

$$\begin{array}{rcl}
 \text{Energy less than 300} & 4.3534 * 10,009,116 \text{ kwh} & = \$ 435,697
 \end{array}$$

$$\begin{array}{rcl}
 \text{greater than 300} & 6.7074 * 91,474,357 \text{ kwh} = & 6,135,633 \\
 \text{Customer} & \$2.90 * 14,800 \text{ bills} & = \underline{42,920} \\
 & & \$6,614,250
 \end{array}$$

It should be pointed out that the 6.7074/kwh will decrease to some extent due to (1) final allowed revenues being slightly less than those presented here and (2) the inclusion of the other residential schedules which are found to have a higher tailblock billing frequency than Sch. 10.

72. In accepting Dr. Power's proposed inverted rates, the Commission is adopting as a paramount objective in ratemaking, economic efficiency principles. The benefits of such pricing is totally dependent on the response of rational consumers weighing the economic costs of electricity consumption with that of both substitute and complimentary goods. For the consumer to make a rational decision, he/she must have knowledge of the rates.

73. The Commission hereby directs the Company to provide on every customer's monthly bill, the actual rates in affect and approved by this Commission. The rate information provided shall fully enable the customer to calculate his/her monthly bill and shall include, for all schedules, as well as Sch. 10, the minimum bill, energy charges per block and per period of time, size of block and dimensions of peak periods, and the demand charges, as appropriate to each Schedule.

74. Although the Company is encouraged to maintain general, water heating, and space heating customer distinctions internally for end use analyses, for purposes of costing, rate regulation, and customer understanding, the distinction is burdensome and serves absolutely no purpose. The costs determined by the Company and accepted by the Commission vary only by time of service and distribution level. The Commission directs the Company to eliminate Sch. 12, 14, 18, 50 and 56 and serve all nontime-of day residential customers on Sch. 10.

Lifeline/Social Equity

75. At this point it is necessary to return to Dr. Power's contention that lifeline-like, inverted rates should be adopted for social equity reasons and clarify whether this Commission has accepted or rejected lifeline rates in establishing an inverted rate structure.

76. Section 114 of PURPA reads in part:

SEC. 114. LIFELINE RATES.

(a) LOWER RATES. -- No provision of this title prohibits a State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or a nonregulated electric utility from fixing, approving, or allowing to go into effect a rate for essential needs (as defined by State regulatory authority or by the nonregulated electric utility, as the case may be) of residential electric consumers which is lower than a rate under the [cost of service standard].

As noted in Dr. Power's testimony, PURPA's definition does not distinguish between residential customers on the basis of age or income level.

77. This record amply shows that the phrase "lifeline rates" connotes different things to different persons: MDU adamantly contends that lifeline rates evolved predominantly from "the undisputed need to help the poor and the aged with skyrocketing [energy] costs, " (Exh. 1, p. 16) while AEM argues that lifeline rates from their inception were intended to fulfill multiple objectives of:

- a) More accurately reflecting the increasing costs of providing electricity, . . .
- b) Promot[ing] energy conservation by more fully reflecting the costs of new electric supply and rewarding low energy consumers,
- c) Provid[ing] electricity for essential uses at a protected low price to all customers, [and]
- d) [Providing] rate relief for most low income households who, by necessity, also tend to be small electricity consumers. (Exh. AEM-1, p. 7)

78. This Commission hereby defines lifeline rates as rates that set the unit price for electricity for all residential consumers' essential needs, which are relatively unavoidable, lower than the price for other needs. This definition makes no mention of the cost basis of the relative prices, nor does it make mention of income levels or rate relief. It has been determined above that inverted rates are consistent with "cost of service" principles and that to the extent long-run incremental costs exceed the tailblock price, rates for all electric service are below cost.

79. Before the matter of what lifeline rates entail can be resolved by the Commission "essential needs" must be defined. Dr. Power outlined four approaches to defining essential needs and then reiterated that the ultimate definition must be consistent not only with social equity objectives but with economic efficiency.

There are several ways [to define essential needs].

The most limited definition would be that amount of electricity which is needed within the household for uses for which there are no practical alternative energy sources. This would be the electricity a modern household would have to use no matter what the price of electricity and the prices of alternative energy sources. Minimal lighting and small appliances such as furnace blowers and refrigerators would be the only "essential needs". Cooking, hot water heating, and space heating can usually be done with natural gas, propane, or fuel oil. Thus electricity, in this approach, is not essential for cooking, hot water heating, and space heating. This definition would suggest that 200-250 kwh/mo. are essential.

A much more liberal approach would study for what households are now using electricity and adjust the definition of "essential" to the uses into which the population is now "locked" by investment in appliances. Thus, if many use electricity for hot water heating, as they do on MDU's system, modest water heating would be allowed for, as would cooking, clothes washing, and so

on. This approach would suggest a 400-600 kwh/mo. definition of essential electricity. For those who have already invested in electric space heating, some modest allowance such as 1000 kwh/mo. might be made during the winter months.

A third approach might be to survey the low income population to see in what way the disadvantaged are dependent upon electricity and try to minimally provide for those uses.

Finally, one could use "community standards" as indicated in surveys of the general population. What is "essential" is certainly a social judgment which shifts as the standard of living changes. Hot water is considered "essential" now but was not 50 or 60 years ago. I do not go into the "essential needs" definition in any more detail because the quantity chosen for this is not independent of the size of the reduction in rate contemplated for this block.

It must be remembered that the- lifeline is a multi-objective proposal. It is not simply- an attempt to reduce the cost of essential electricity. It also has cost and conservation objectives. If the block for essential needs is made quite large, the reduction in the charge for it must be quite small or conservation will not result because many consumers will be given misleading cost information. On the other hand, if the essential needs block is made quite small, the rate charged for it can be lowered to even zero without affecting conservation or price signals. Thus, one could join Florida and define 750 kwh/mo. as essential but lower the rate on that amount only slightly. Or one could adopt the proposal of the Oregon Public Utilities Commissioner's Staff to provide 200 kwh/mo. at no charge. One could be even more stingy and propose, as a consumer group in Iowa has, that 50 kwh/mo. be provided at no charge.

California walked a middle line, but an administratively more complex one. It defined a lifeline for each major use, lighting and appliances, hot water and space heating. It also varied the essential home heating amount by climatic area. The reduction was then more or less set at 25 percent. This tailors the "essential needs" block to appliance ownership and assures that

most individuals face accurate tail block rates. If to provide some relief to all electric homes the essential needs amount was set relatively high (e. g., 1200-1500 kwh/mo. during the winter) many using other fuels would be getting quite distorted price signals. My point is that the "essential needs" can be defined in many, quite different but legitimate ways. The choice of one is a policy decision which has to be influenced by considerations unassociated with what needs are essential, namely conservation and tail block price distortions.

80. Recognizing that Dr. Power acknowledged that seasonal lifeline rate of 400 kwh/mo. in winter and 250 kwh/mo. in the summer would be preferable to a constant 300 kwh/mo. lifeline but that the billing frequency data, by season or month, is not currently available to construct such rates, the Commission finds that an initial block of 300 kwh/mo. would serve the purpose of providing electricity for essential needs, without encumbering and conservation objectives. With such a block 91 percent of all Sch. 10 energy sales will be sold to customers at the tailblock rate.

81. MDU objected to lifeline rates on the basis, inter alia, that there is an imperfect correlation between income and consumption. Their objection is relevant only if one were to define lifeline as the provision of rate relief to low income customers. The fact that MDU witness Dr. Richard Kaufman's testimony concludes that 90 percent of low income individuals would be benefited by lifeline rates, as compared to the declining block rates MDU proposed, merely points out the beneficial, yet consequential, implications of a lifeline.

82. The Commission finds that the inverted rate structure, melding social equity and economic efficiency considerations, appropriately provides a lower rate for essential needs of all residential customers, irrespective of age or income level.
Commercial/Sch. 20

83. The Company's proposal for structuring a Sch. 20 tariff includes a customer charge of \$10, a demand charge for all billing demand beyond 10 kw,

and three declining energy blocks. Dr. Wilson proposes a flat energy rate with a customer charge of \$30.55 for nondemand metered customers. A separate rate for demand metered customers features a flat energy rate, the same customer charge, and a demand charge for all levels of kw.

84. The Commission recognizes that serving a combination of nondemand metered and demand metered customers on one tariff requires a balancing of demand/energy charges. However, the Commission rejects the Company's proposed declining block rate and directs the Company to structure, instead, separate general service tariffs for nondemand and demand metered customers.

85. The Commission finds disturbing the Company's proposed "cost-based" declining blocks, when in fact, Mr. Chick concedes that:

. . . the Rate 20 shown under the TAB Exhibit D in the Company's filing are a continuation of historical numbers which have been in the Montana rate structure and which have been percentaged up in other ways to produce the revenue requirements for Rate 20 which was shown I believe on Exhibit J-2. (Tr. 163)

86. Furthermore, the Commission finds that the same economic efficiency objective that leads to inverted residential rates, could as well be applied to general service rates. Short of inverting the rates, the Commission directs the Company to design two general service schedules, both featuring a minimum bill of \$10.30 and flat energy charges. The demand metered schedule shall have, in addition to flat energy rates and a minimum bill, a nominal demand charge of \$2 . 00/kw for all billing demand above 10 kw. The nominal demand charge, as opposed to the \$3.00/kw found on the existing interim tariff, will partially offset the misallocated demand/ energy calculation sponsored by Mr. Ketchum and accepted by the Commission for lack of a better alternative. The discount for primary service should be reflective of Mr. Ketchum's LRIC, 3 percent, and should apply to both energy and demand to reflect line loss savings.

87. As with the residential customer class the Commission finds burdensome and of no purpose Sch. 21, 22, 33, 50 and 52. The Company is directed to eliminate these tariffs and serve all nontime-of-day commercial customers on either the demand metered or nondemand metered tariffs. Any necessary provisions for selected customers should be set forth on the respective Sch. 20 tariff.

Large Commercial & Industrial/Sch. 30

88. Both the Company and Dr. Wilson propose mandatory time-of-day rates for Sch. 30 customers. A discussion of the evidence and the Commission's findings in respect to time-of-day rates is provided below.

TIME-OF-DAY RATES

89. Time-of-day (TOD) rates were proposed by MDU and MCC. Both advocated that mandatory rates be established for the industrial class and that optional rates be available to residential and general service classes. AEM opposed the practice of TOD pricing, contending that it was shortsighted, promotional and detrimental to alternative energy investment within the residential sector; however, on cross-examination, Dr. Power admitted that, theoretically, "one would like the price to accurately and continuously reflect the level of costs." (Tr. p. 351)

90. This Commission is in agreement with Dr. Power: to the maximum extent practicable, rates should reflect the time-varying nature of MDU's costs. The question is not whether MDU's costs vary according to time of use: the charts attached to Appendix A of Mr. Ketchum's testimony ably summarize ample evidence in the record that MDU's hourly running costs are characterized by a substantial diurnal variation. What the Commission has sought in this docket and in Docket No. 6695, and what the parties have yet to agree upon, is the point at which, either in terms of individual customer characteristics or customer classes, TOD pricing is cost-effective.

91. MDU was hesitant to assert that time-of-day pricing is cost effective even for large industrial customers because a cost effectiveness test has not been done. Mr. Ketchum posited that an average residential or small commercial customer cannot possibly shift enough load to make time of day rates cost beneficial; in addition, he said that current load research data did not enable them to analyze the patterns, and hence cost/benefits, of larger customers. He did, however, note that small percentage shifts-perhaps as slight as 1 percent-by very large customers, such as oilfield operators, may be cost-effective. Nevertheless, Mr. Ketchum recommended deferral of mandatory time-of day rates for industrials until individual interviews can be held with each large customer to determine their potential for shifting load, and bill comparisons, based on allowed revenues and proposed TOD day rate designs, can be done. Notwithstanding Mr. Ketchum's comments and their own reservations, MDU proposed mandatory TOD rates for industrials in the interest of promoting cost based rates and collecting data regarding the impact of TOD rates.

92. Dr. Wilson, on the other hand, did not recommend suspending implementation of all mandatory TOD rates, pending a system-specific cost - effectiveness investigation. While he conceded that in most instances, the costs exceeded the benefits v`Then fairly small residential or general service consumers were subjected to TOD rates, he stated that for customers whose average consumption is 1.5 million kilowatt hours per year "it [is] clear that the benefits will exceed the costs under almost any reasonable assumptions." (Tr. 287) Even though Dr. Wilson said it was conceivable that the cost/ benefit test could be met for many customers consuming anywhere between 10, 000 to 100, 000 kwh per year, he recommended that, as yet, mandatory rates be applicable only at a fairly large level of consumption-perhaps one million kwh per year-and that the rates should apply to such large customers, irrespective of whether they take service at primary or secondary levels. So long as there is compensation for the cost

differential of providing secondary level service, Dr. Wilson contended it was appropriate to employ mandatory TOD rates for all large customers.

93. As with the regular rate schedule proposals, the appropriate level for customer charges or minimum bills under optional TOD rate schedules was disputed. MDU proffered proposals containing monthly customer charges bills of \$10.55 for residential customers, and \$14.50 and \$15 .30, respectively, for nondemand and demand metered general service customers. Mr. Ketchum's marginal based rate design set forth the additional costs related to time of use meters: for residential customers, the cost increment is \$2.75 per month; for general service customers, it is either \$4.04 or \$5.49, depending on whether nondemand or demand schedules are used. Mr. Fox added these charges to what Mr. Ketchum calculated marginal customer-related costs to be on a monthly basis. Hence, the customer charge/minimum bill proposal for residential customers opting for time of day pricing was a fully compensatory \$10.55 while the minimum bill proposal for regular residential customers was one half that amount. Mr. Fox explained that the \$10.55 charge was predicated on a desire to test "whether in fact TOD rates are beneficial. " - (Tr. p. 82) Moreover, he stated that it was in accord with MDU's expressed concerns for customer understanding and simplicity in rate design since MDU would have the opportunity to explain to TOD customers the rationale underlying all charges on a one to one basis.

94. On cross-examination Mr. Ketchum lent little support to MDU's fully compensatory, marginal cost-based customer charge. Mr. Ketchum admitted that, given a \$4.00 customer charge/minimum bill for regular residential customers, MDU could have opted for \$6.75 monthly charge for time of day customers. Furthermore, to the extent that the regular schedule customer charges were not fully compensatory, Mr. Ketchum conceded it was discriminatory, to subsidize some customers, and not others.

95. MCC's customer service charge proposals were identical for regular and TOD residential and general service customers. Although Dr. Wilson stated during cross-examination that he "would not object to an addition of an appropriate amount [to the charge] to reflect the higher metering costs," he believed that "the customer charge should be about the same for the time of day as proposed for nontime-of-day customers...to the extent you impose a substantially different up-front customer charge, you're going to be either improperly encouraging or discouraging the choice or reluctance to choose the time of day rate option. " (Tr. pp. 290, 291) Dr. Wilson reassured the Commission that the additional metering costs which MDU incurs should be collected but noted that the mode of collection via customer or energy charges-is unimportant.

96. Based on the evidence in the record, the Commission finds that the proper approach to TOD pricing for MDU is to maintain the existing optional Sch. 16 (residential), Sch. 23 (nondemand metered general service), and Sch. 26 (demand metered general service) as proposed, and institute a mandatory TOD Sch. 30.

97. The Commission finds that the customer charges proposed for the optional TOD tariffs should be the same as those found in Sch. 10 and 20. That is, no customer charges, but a minimum bill of \$2.90 and \$10.30, respectively. The tariffs need promotion. The customer charges, as proposed, reflect a blatant discouragement to potential TOD customers. Each customer who rationally opts for the TOD schedules will realize a cost savings which will be passed to the Company and eventually, to all MDU ratepayers. The additional costs of the TOD meter, as determined by Mr. Ketchum, shall be recovered through energy charges and spread equally between the on and off-peak periods.

98. The subject of promoting the tariffs has been discussed in previous proceedings. The Company must take the initiative in ardently promoting the

tariffs, and this effort should begin with a billing insert subsequent to approval of the tariffs.

99. The nondemand metered optional tariffs (Sch. 16 and 23) should be structured to reflect energy charges with a 2:1 price differential. The Commission chooses to approach the price differential conservatively to reflect a compensation for the LRIC demand/energy imbalance and to reflect the fact that the price elasticity of demand will tend to reduce the differential overtime. The 2:1 differential is reflective of the existing differential, more closely reflects the variation in marginal energy costs, and provides a buffer, recognizing that the differential will tend to decrease over time.

100. Sch. 16, specifically, shall provide the on-peak, off-peak differential, and additional TOD metering costs to only that consumption in excess of 300 kwh per month. The initial 300 kwh per month shall be priced at 4.3534/kwh, regardless of time of consumption.

101. Sch. 26, optional TOD for demand metered general service, shall be structured similar to Sch. 23, with the exception of a nominal \$2.00/kw demand charge.

102. In respect to the mandatory TOD Sch. 30, the Commission finds that it shall feature a nominal demand charge of \$3.00/kw, as opposed to the existing \$5.00 charge, the same 2:1 energy price differential, a minimum bill of \$10.30, and shall apply to all large commercial and industrial customers with loads averaging greater than 1,000,000 kwh per year. This should include the 15 contract customers served under Sch. 30, as well as the, approximately, 11 oil field power customers previously served under Sch. 33 whose consumption averages greater than 1,000,000 kwh.

103. Language in the existing TOD tariffs that, as a condition for service, forbids the use of supplemental energy sources, shall be deleted.

104. In Order No. 4635c, Docket No. 6695, the Company was directed to design a TOD pricing experiment for purposes of assessing the economic rationale in establishing mandatory TOD rates for all customers. The Commission directs the Company to record and collect data, monitoring the load patterns resulting from mandatory TOD pricing. Such data should be designed to provide the basis for an analysis leading to the cost/benefit information necessary for assessing the rationale in establishing mandatory TOD at successively lower levels of consumption. This effort will suffice for purposes of a TOD experiment.

105. In reference to the applicability of the irrigation load to mandatory TOD, Mr. Chick stated that it is indeed a "fertile field" for TOD and that the Company would be willing to provide the Commission with an examination of its applicability. The Commission finds merit in Mr. Chick's suggestions and directs the Company to initiate such examination.

OTHER SCHEDULES

106. The Company has not provided cost analysis in respect to the provision of electricity to pumping (irrigation and municipal) or lighting. Given that costs vary only by time of service and distribution level, the Commission finds that the Company shall design a Sch. 25 applicable to all pumping (irrigation and municipal) and a schedule applicable to all lighting which are consistent with the Commission's previous findings in this Order. Services rendered for both pumping and lighting shall be priced correspondingly and shall feature minimum bills reflecting that found on Sch. 20.

107. The Commission directs the Company to eliminate Schedules 24, 28, 41, 42, 43, 47, 48 and 49 and to provide the lighting customers with access to the optional TOD general service schedules.

108. Two remaining tariffs require brief discussion and finding. The Company's Schedules 27 (Feed Grinding) and 51 (Controlled Residential and

Commercial Electric Water Heating) are, implicitly, offerings of interruptible service. The Commission intends to address load management, including the provision of interruptible rates, in a subsequent Order. The Company is directed to grandfather Sch. 27 and 51 and freeze the existing rates until such time that the record in Phase II regarding interruptible rates and load management has been fully examined by the Commission.

109. The consolidation of tariffs leaves the Company with the same basic tariff schedules found in the tariffs of the other major electric utilities in Montana, eliminates the burden associated with regulating 26 schedules, promotes customer understanding, and provides service of equal costs at equal rates.

COMPENSATION FOR CONSUMER INTERVENORS IN PURPA-RELATED PROCEEDINGS

110. The Commission finds that the testimony sponsored by Action for Eastern Montana, through its expert witness Dr. Power, has substantially contributed to the adoption of the rate design found appropriate in this proceeding .

111. The Commission finds that Action for Eastern Montana is entitled to reimbursement for reasonable costs of participation and that on October 13, 1981, AEM, through its attorney, Phyllis A. Bock, submitted an Affidavit detailing the costs to which they claim they are entitled.

112. Pursuant to Commission rules, MDU has ten days from the date of this Order to object to the accounting, and reasonableness of, AEM's participation costs.

CONCLUSIONS OF LAW

1. The Applicant, Montana-Dakota Utilities Company, is a "public utility" within the meaning of Montana law, Section 69-3-101, MCA.

2. The Commission properly exercises jurisdiction over the Applicant's rates and operations pursuant to Sections 69-3-102 and 69-3-302, MCA.

3. The Commission acts in its legislative capacity when it allocates utility costs to the various customer classes.

4. In establishing a rate structure the Commission may take into consideration both cost factors and noncost factors.

5. The objectives of conservation, efficiency and equity are promoted by the rate structure approved in this Order.

6. The rate structures authorized by the Commission, based upon analysis of the entire record, are just, reasonable, and not unjustly discriminatory.

ORDER

1. MDU shall design rates to generate authorized revenues which are Fact entered by the Commission in this consistent with the Findings of Order. These rates shall be designed as summarized below.

- a) Utilizing MDU's long-run incremental cost analysis, establish, for all classes of customers, class revenue responsibility based on an equal percent of class incremental costs.
- b) Eliminate, for all classes of customers, all nonusage sensitive basic, service, or customer charges, and establish minimum bills at the levels directed.
- c) Structure all energy charges, excepting Schedules 16, 23, 26 and 30, such that the charge per kwh remains constant at all levels of consumption, except that the first 300 kwh of monthly Schedule 10 and 16 consumption shall be priced at 4.3504/kwh.
- d) Provide a two-to-one daily differential for energy charges in Schedules 16, 23, 26 and 30, for all levels of consumption in Schedules 23, 26 and 30 and for levels greater than 300 kwh in Schedule 16.

2. In submitting tariffs in compliance with this Order, MDU shall also submit working papers revealing, in detail, the structuring of the rates.

Done and Dated this 19th day of October, 1981, at Helena, Montana by a
5 - 0 vote .

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

GORDON E. BOLLINGER, Chairman

JOHN B. DRISCOLL, Commissioner

HOWARD L. ELLIS, Commissioner

CLYDE JARVIS, Commissioner

THOMAS J. SCHNEIDER, Commissioner

ATTEST:

Madeline L. Cottrill
Commission Secretary

(SEAL)

NOTE: You may be entitled to judicial review of the final decision in this matter. If no Motion for Reconsideration is filed, judicial review may be obtained by filing a petition for review within thirty (30) days from the service of this order. If a Motion for Reconsideration is filed, a Commission order is final for purpose of appeal upon the entry of a ruling on that motion, or upon the passage of ten (10) days following the filing of that motion. cf. the Montana Administrative Procedure

Act, esp. Sec. 2-4-702, MCA; and Commission Rules of Practice and Procedure, esp. 38.2.4806 ARM.